10/618328

E21B47/06 E21B47/06B E21B47/12M2

E21B47/10

Fiber-optic systems for reservoir monitoring

XP-000880352

V644

p.d. 10-1999

An array of fiber-optic sensors and formats, including fiber Bragg gratings, is helping smartwell designs become even smarter

p. 91-93+96-97 = (5)

A. D. Kersey, D. L. Gysling, Wallingford, Connecticut and **F. X. Bostick,** Houston, Texas, CiDRA Corp.

Fiber-optic-sensor technology has been under development for the past 20 years and has resulted in several successful new products; fiber-optic gyroscopes, temperature sensors, acoustic sensors, accelerometers and chemical probes are examples. Applications include structural monitoring, military systems (e.g., underwater acoustic arrays), industrial applications (e.g., process-control sensor networks), chemical sensing (distributed spectroscopy) and security monitoring (intrusion detection), to name a few.

This technology is now creating new capabilities for sensing a wide range of parameters, such as pressure, temperature, vibration, flow and acoustic fields. These can now be applied to downhole oil and gas reservoir-monitoring applications for both retrievable and permanently installed systems. Several types of fiber-optic sensors have been demonstrated for in-well use, including a distributed temperature sensor for temperature profiling, an optically excited, resonant pressure sensor, an interferometric point sensor for pressure monitoring and Bragg-grating-based sensors for a range of parameters.

Transducers are being developed that are based on Bragg-grating technology for a wide range of oil and gas industry applications. These are not limited to downhole-production monitoring, but include seismic sensing, downstream-process monitoring, platform/structural/pipeline monitoring and other sensing requirements in the E&P industry. This paper explores downwell-monitoring applications of this technology.

INTRODUCTION

Modern completions can be complex; the reservoir can be split between multiple levels, with each zone producing at differing rates, gas/oil/water ratios, pressures and temperatures. The reservoir engineer's goal is to recover most of the hydrocarbon reserves in the field. Unfortunately, current recovery efficiency averages only about 35%. To optimize recovery efficiency, the industry is turning toward enhanced-well and reservoir-management techniques, such as "smartwells" or "intelligent" completions. Inherent to this trend is the need to deploy permanent-sensor capability in the wellbore.

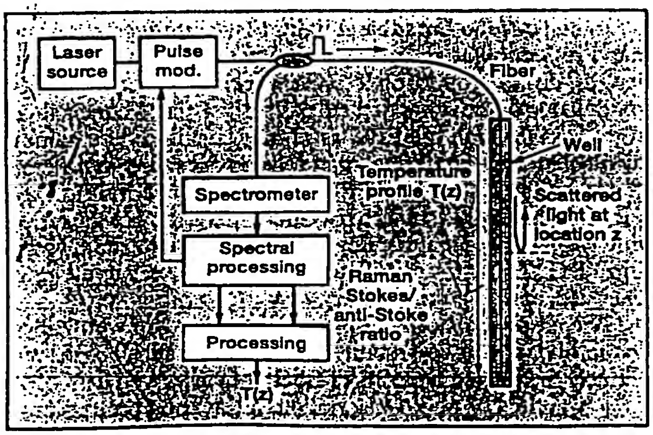

Fig. 1. Distributed temperature sensing using Raman scattering. The fiber itself is the sensing element.

Pressure and temperature are fundamental reservoir-engineering parameters, and permanent monitoring of downhole pressure and temperature is widely utilized.[1] While conventional pressure and temperature sensors are proving to be important reservoir-management tools, the current technology has some important limitations—primarily, failure of required downhole electronics at elevated temperatures. In addition, multiplexing restrictions limit the spatial resolution provided by conventional sensors.

The use of fiber-optic technology, particularly for downhole applications, is driven by the inherent advantages of fiber optics over conventional-sensor technology, such as:

- No downhole electronics required
- Intrinsically safe
- Immune to electromagnetic interference
- Operate at high temperatures (175°C, or above in some cases)
- Can be multiplexed or operated in a distributed mode, thus allowing spatial profiling
- Small cross-section, low-profile sensors, minimally invasive in the wellbore.

DOWNHOLE SENSOR FORMATS

One of the most widely deployed fiber sensors in downwell-monitoring applications is the Raman backscatter distributed temperature sensing (DTS).

DTS. Raman scattering is an effect in which light passing along a fiber is scattered off glass molecules within the fiber.

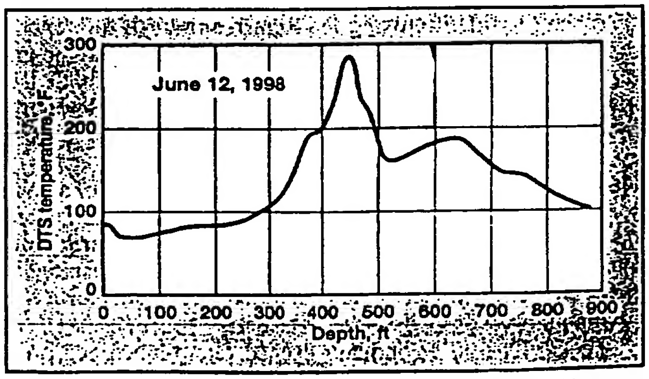

Fig. 2. Example well profile, typical for steamflood, using distributed temperature sensing.

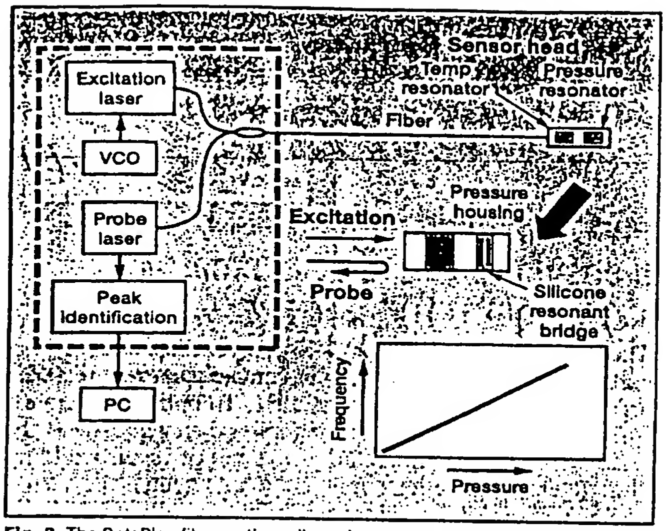

Fig. 3. The OptoPlan fiber-optic well monitor system. Laser light excites silicon oscillator, the latter's resonance frequency changes with pressure. Inset shows resonance frequency vs. pressure.

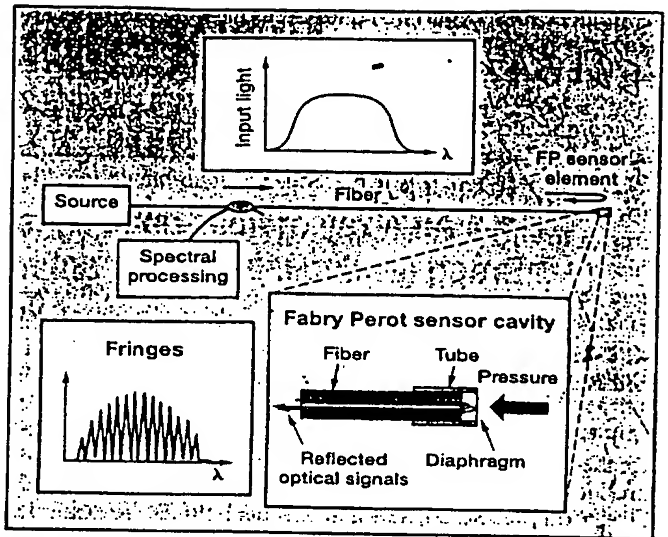

Fig. 4. Fabry Perot optical cavity creates interference in light reflected from sides of a pressure-sensitive cavity. Interference fringes relate to changes in cavity dimensions, allowing pressure measurement.

In the scattering process, energy is transferred between the light and the vibrational energy of the glass molecules.[2] The light undergoes either a frequency upshift (higher energy) or a frequency downshift (lower energy). The frequency upshift/downshift ratio of the scattered light is a function of temperature of the glass.

This approach has begun to find widespread use in borehole-temperature profiling, particularly in steamflood wells, Fig. 1. The temperature profile provided by DTS instrumentation can be used to provide insight into borehole-to-reservoir heat flow, thus optimizing production.

Fig. 2 shows an example of an in-well DTS profile. The well is relatively shallow, and the injected steam can be observed creating a hot region around a depth of 450 ft. In addition to the general advantages of fiber optics, the Raman approach has certain benefits for downhole use:

- Truly intrinsic DTS concept
- Operates throughout a long fiber length (several km)
- Unaffected by pressure/fiber strain.

However, the approach has limitations that include:

- Spatial sensing limited to 1- to 3-m resolution due to the optical pulse "width" in the fiber, i.e., temperature is not resolvable to a point along the fiber
- Technique suitable only for temperature monitoring
- Expensive surface instrumentation
- Slow data processing due to inherently weak signal.

When considering using the Raman approach for general reservoir monitoring, the fact that it provides only a temperature profile is the most significant drawback. In that case, multi-parameter sensing is required, i.e., pressure, temperature, flow, acoustics, etc.

Reservoir pressure monitoring. An example of a point sensor designed to monitor bottom hole pressure (BHP) is one developed by OptoPlan A.S. This work, which was originally supported by Alcatel Kabel and Shell Norge, has resulted in successful deployment of several sensors in some North Sea producing wells.

The device uses an optically excited, micro-machined, pressure-sensing, silicon oscillator element in which stress, produced via the external pressure field, changes the resonant frequency of the element, Fig. 3. To overcome output-frequency dependence on temperature, a temperature-compensating oscillator element is included in the sensor head, the frequency of which varies only with temperature and can thus be subtracted from the primary pressure-sensitive-element response.

Extrinsic point sensor. An example of a point sensor is an extrinsic Fabry Perot Interferometer (FPI) formed by two reflecting surfaces. In this type of system, an optical micro-cavity is bonded to the end of a fiber tip, Fig. 4. Light passing along the fiber is reflected off the FPI and back toward the input. The reflectivity of the FPI depends on cavity spacing between the two reflectors. Allowing cavity spacing to be dependent on external pressure, for example, provides a basis for a pressure sensor. However, the basic approach is non-absolute, i.e., the interference pattern formed is cyclic and non-unique. It is also difficult to multiplex more than just a few devices.

Bragg grating sensors. Fiber Bragg gratings (FBGs) are intrinsic sensor elements that can be "written" into optical fibers via a UV photo-inscription process.[3] The process produces a periodic modulation in the index of the glass fiber, which is a stable structure even at downhole temperatures. This periodic modulation constitutes a resonant optical system.

In response to broadband light, FBGs produce a narrowband reflection at an optical frequency, or equivalent wavelength, that is proportional to the wavelength of the periodic modulation of the refraction index, Fig. 5. Other frequencies of light pass through the FBG essentially unaltered, remaining available for interrogating other sensors operating at different frequencies. Thus, several FBG sensors can be multiplexed, Fig. 6. If the FBG is subjected to strain, frequency of the reflection is altered in a manner directly proportional to strain within the FBG. Thus, the FBG can be viewed as a wavelength-encoded, optical strain gauge.

The advantages of Bragg grating sensors are well known in the fiber-sensor community. They incorporate all of the previously mentioned benefits of fiber optics, as well as:

- Simple, UV photo-inscription, fabrication process
- Intrinsic intra-core sensor element
- Wavelength-encoded operation

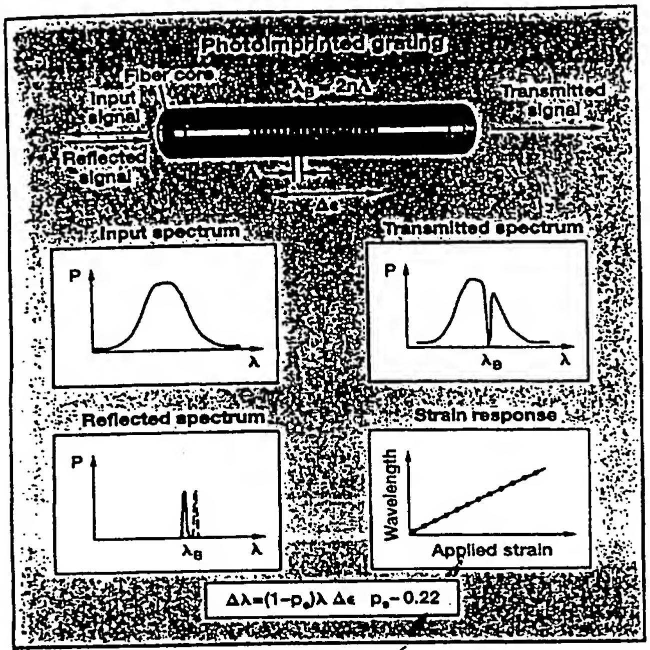
Photoimprinted grating
Fiber core
Input signal
$\lambda_B = 2n\Lambda$
Transmitted signal
Reflected signal
$\Delta\varepsilon$
Input spectrum
P
λ
Transmitted spectrum
P
λ_B
λ
Reflected spectrum
P
λ_B
λ
Strain response
Wavelength
Applied strain
$\Delta\lambda = (1 - p_e)\lambda\,\Delta\varepsilon \quad p_e \sim 0.22$

Fig. 5. Bragg grating sensors. Reflected signal is narrowband. Strain shifts the wavelength (frequency) of reflected band slightly, which is proportional to parameter being measured.

- Distributed-sensing capabilities
- Low-profile sensor
- Compatible with components developed for the fiber-telecommunications market.

CiDRA is developing a range of transducers that use Bragg gratings as the core building block for a suite of wavelength-encoded sensors. This allows development efforts to be based on a *common technology platform* in which all types of transducers are compatible with a single form of surface instrumentation, allowing "plug-and-play" capability in downwell-sensor systems.

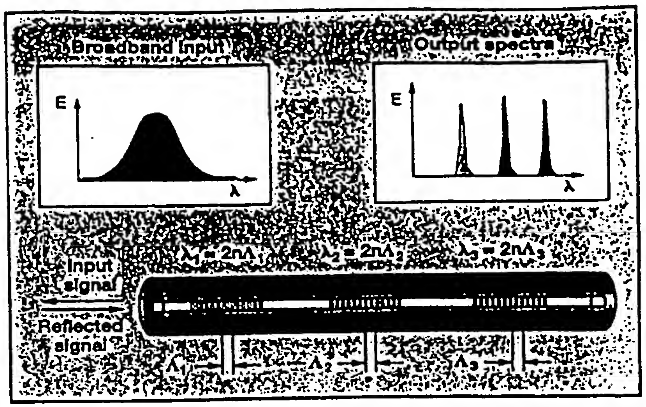
Broadband input
Output spectra
E
λ
E
λ
$\lambda_1 = 2n\Lambda_1$
$\lambda_2 = 2n\Lambda_2$
$\lambda_3 = 2n\Lambda_3$
Input signal
Reflected signal
Λ_1
Λ_2
Λ_3

Fig. 6. In FBGs, transmitted signal is available for measurement of other parameters. Since each FBG is designed to create a different reflected wavelength, output signals are multiplexed. Only three are shown, but many more signals are possible.

Transducers for pressure, temperature and vibration have been built and tested, and concepts for differential pressure, acoustics, corrosion and resistivity are under development. As discussed below, multiphase flow sensors have passed the technology-demonstration phase. The goal is to provide pressure, temperature and multiphase flow on a distributed basis throughout producing wells, with sufficient resolution to optimize reservoir production. These sensors can be applied to applications for retrievable or permanently installed reservoir-monitoring systems.

DOWNHOLE MULTIPHASE-FLOW MONITORING

The industry has successfully overcome many of the challenges associated with topside multiphase flowmeters. These challenges are generally more restrictive downhole, although the physics of multiphase flow sometimes creates conditions downhole that are somewhat more conducive to multiphase-flow measurement.

A variety of multiphase-flow conditions can be encountered in oil and gas wells, Fig. 7.[4] In the scenario depicted, a hydrocarbon/water mixture was produced through a vertical production tube from an undersaturated reservoir.

From a multiphase-flow measurement perspective, the nearly homogeneous, liquid-, bubbly- and misty-flow regimes are easier to measure. The non-homogeneous slugging, churning and annular flows are more challenging, often requiring intrusive flow mixers, or similar devices, to make accurate measurements. These non-homogeneous flows are generally encountered by topside, multiphase flowmeters, independent of the flow regime in which reservoir fluid enters the production tubing.

Continued

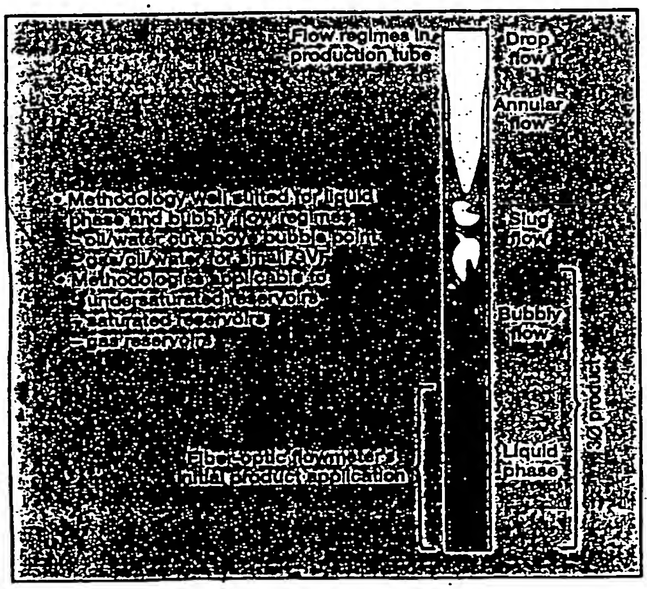
Flow regimes in production tube
Drop flow
Annular flow
Slug flow
Bubbly flow
Liquid phase
• Methodology well suited for liquid phase and bubbly flow regimes:
– oil/water cut above bubble point
– gas/oil/water for small GVF
• Methodologies applicable to
– undersaturated reservoirs
– saturated reservoirs
– gas reservoirs
Fiber-optic flowmeter's initial product application
3Q product

Fig. 7. Typical multiphase flow regimes.

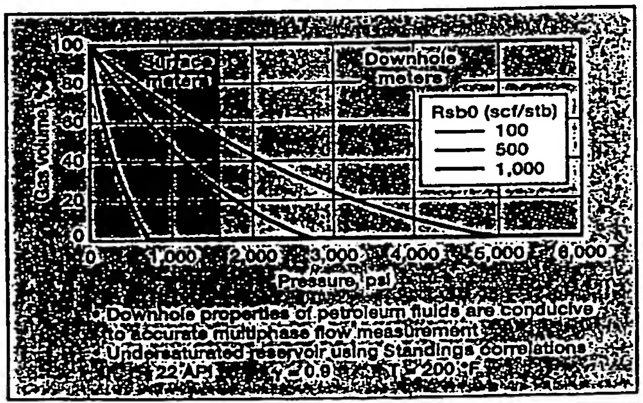

Fig. 8. Prediction of gas-volume fractions in produced fluids. Above about 3,000 psi, most flow is nearly homogenous. Rsb0 is the amount of dissolved gas at bubble point pressure and reservoir temperature.

Fig. 8 shows the gas volume fraction as a function of pressure for several oils with different gas/oil ratios. The gas-volume fractions are predicted using Standing's correlations.[5] As shown for this example, at pressures above roughly 3,000 psi, all three fluids are in either liquid- or bubbly-flow regimes. At the lower pressures that surface flowmeters must operate, high gas-volume fractions indicate that flows are, to a varying degree, in the difficult-to-measure, non-homogeneous flow regimes.

This simplified example illustrates that the flow physics, due primarily to pressure, are more conducive to measurement at downhole conditions rather than at surface conditions. As evidence that these conclusions are indicative for a broad class of production scenarios, venturi-based flowmeters, targeted at homogeneous flow regimes, have been successfully deployed for use downhole.[1]

Fig. 9. Multiphase flowmeter deployment into test well.

Fiber-optic multiphase-flow measurement. Exploiting the inherent capabilities of Bragg fiber-optic sensors to accommodate harsh temperatures, packaging, environmental and data-transmission requirements, the company is developing a downhole, multiphase flowmeter.

The flowmeter is non-intrusive and contains no downhole electronics. The initial meter is targeted at quasi-homogenous flow regimes comprising liquid mixtures with either low (<20%) or high (>90%) gas volumes. To evaluate performance of the new multiphased flowmeter, the company employed an independent, industry-recognized, test-well facility, Fig. 9. Test objectives were focused on the nearly homogenous, limited-flow regimes described above.

The flowmeter was designed into a standard 3.5-in. production tube, about 12-ft long. A 7-ft long, 5.5-in. piece of production tubing was used as a protective sleeve during testing. These dimensions do not represent minimum-envelope requirements for future products.

The oil, water and gas components comprised 32°-API crude, 7% salinity brine and methane. This was a low-pressure (<400 psi), low-temperature (38°C) test. The crude was exposed to a methane gas head within the separator.

The flowmeter was integrated into the production tubing of a 300-ft test well. The meter was oriented vertically within the well and performed the structural role of a tubing section. The meter communicated with surface-based optoelectronics via a single, armored fiber-optic cable assembly. The test facility combined oil, water and gas prior to testing, separating them at the surface. By monitoring the flowrate of each component, the facility could produce arbitrary multiphase-flow mixtures.

Phase fraction measurement. A primary test objective was to assess the flowmeter's ability to measure watercut in crude/brine mixtures. Fig. 10 shows the measured volumetric phase fraction vs. the reference measurement for watercut, ranging from 0–100%. The reference measurement was determined from flowrates of the individual liquids before being mixed and passed through the test section.

The meter was calibrated by measuring 100% water and 100% oil mixtures before calculating the phase fraction of intermediate mixtures. For production-monitoring applications, industry-required measurement accuracy is about 10% relative uncertainty in gas-liquid rates and 5% uncertainty in water-in-liquid ratio.[1] As shown, with the exception of a few outlying data points, the flowmeter was able to determine watercut in crude and brine mixtures to within ±5% throughout the full range of watercuts.

In addition to addressing ability to measure watercut, the test also assessed the flowmeter's ability to measure gas-volume fraction in oil/water/gas mixtures. For this test, the mixtures were restricted to low gas-volume fraction and restricted to determining gas-volume fraction in a mixture in which the oil/water ratio is known. Analysis indicates that the meter was capable of determining gas-volume fractions within liquids in the bubbly-flow regime.

Flowrate. Multiphase flowmetering requires flowrate measurement in addition to phase fraction. Flowmeter ability to measure velocity was evaluated for 0% to 100% oil/water mixtures. Velocities ranged from about 1 ft/sec (22 gpm) to 25 ft/sec (548 gpm).

Flowmeter measurement agreed with the reference flowrate for oil/water mixtures to within about 5% throughout the tested flow range, Fig. 11. It should be noted that this is uncalibrated data; accuracy improves after calibration to the reference flowrate. Although not presented here, the flowmeter performed similarly for low gas-volume-fraction mixtures of oil/gas/water.

SCOPE OF POTENTIAL APPLICATIONS

Applications of these new downhole monitoring tools include:

- Permanently installed production/reservoir monitoring:

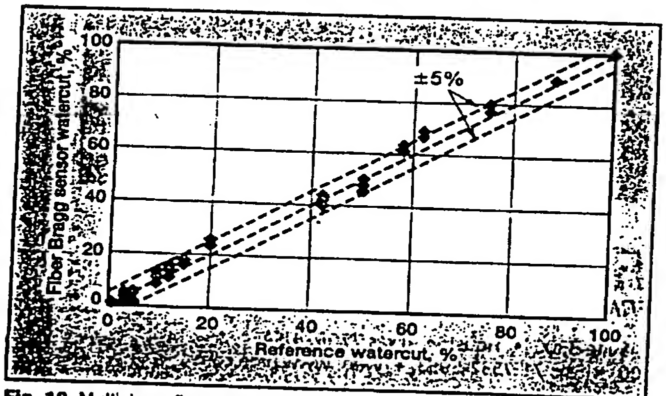

Fig. 10. Multiphase flowmeter, in-well watercut test data showing good agreement (±5%) with reference watercut.

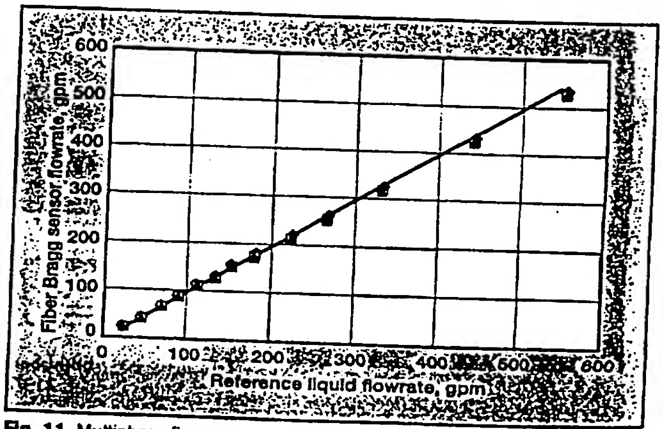

Fig. 11. Multiphase flowmeter, in-well flowrate test data showing close agreement (±5%) with reference flowrate.

1) distributed pressure/temperature/flow/acoustics along vertical, horizontal and multilateral wells; and 2) water breakthrough detection

- Artificial lift: 1) ESP performance/condition monitoring; and 2) steam and gas-lift optimization
- Smart completions
- Formation subsidence monitoring.

In addition, the company is developing a range of in-well, seismic-monitoring systems for VSP, crosswell and passive seismic monitoring.

CURRENT STATUS

In addition to pressure and temperature transducers, the company has developed the necessary surface instrumentation, cables, connectors and feed-throughs for complete fiber-optic pressure and temperature measuring systems. The fiber-optic cable is deployed in a manner similar to electrical cables commonly deployed in conventional reservoir-monitoring systems. During development of its fiber-optic sensing systems, the company collaborated with OptoPlan A.S., which contributed to successful deployment of fiber-optic-based sensor systems in North Sea producing wells.

The current full-up system specifications are:

Pressure sensor:

- Range: 0 up to 15,000 psi
- Overpressure limit: 18,750 psi
- Accuracy: ±6 psi
- Resolution: 0.3 psi
- Long-term stability: ±5 psi/yr (@ 150°C continuous)
- Temperature operating range: 25 to 175°C.

Temperature sensor:

- Range: 0 up to 175°C
- Accuracy: ±1°C
- Resolution: 0.1°C
- Long-term stability: ±1°C/yr (@ 150°C continuous).

Two-phase flowmeter:

- Flow range: >3 ft/s
- Flow rate accuracy: ±5%
- Watercut Range: 0–100 %
- Watercut accuracy: ±5%
- Operating temperature range: 0 up to 150°C
- Operating pressure range: 0–15,000 psi.

In March 1999, the company deployed a test, pressure-monitoring system in a production well in Bakersfield, California. Although this well does not represent a high-temperature, high-pressure environment, it did provide a test of the deployment system in a 2,200-ft well. Following completion, a comparison of pressure readings was made between a fiber-optic gauge vs. a reference surface gauge during initial well drawdown, Fig. 12. The results were in close agreement. These systems have just been released for commercial sale.

SUMMARY

CiDRA is developing high-temperature, fiber-optic, reservoir-monitoring systems. FBG-based pressure and temperature-measurement systems have been designed and qualified and are in various stages of field deployment and commercial use. A fiber-optic based, multiphase flowmeter is under development and has completed a technology-demonstration well test. In this test, the flowmeter demonstrated the ability to measure watercut, gas-volume fraction and flowrates for low gas-volume-fraction mixtures of oil/gas/water. The flowmeter is non-intrusive and contains no downhole electronics.

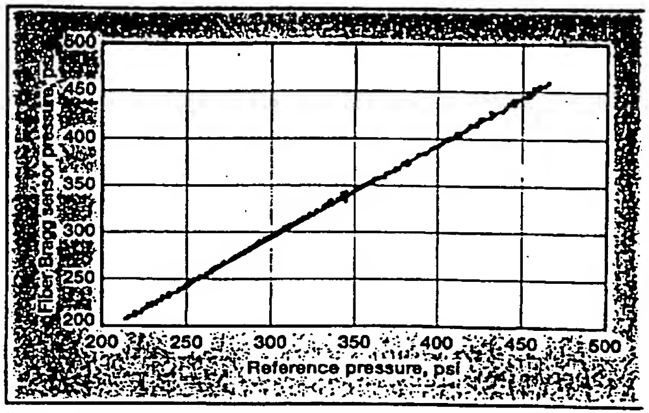

Fig. 12. Comparisons of drawdown-pressure monitoring during an in-well tes (surface gauge vs. FBG gauge).

The high operating temperature and multiplexing capabilities of fiber-optic sensors have the potential to increase both reliability and resolution of downhole pressure and temperature measurements.

The full suite of pressure, temperature and multiphase flow sensors share a common fiber-optic operating principle and can be multiplexed on a single fiber. When available, the full line of fiber-optic sensing systems will provide enhanced capability to monitor reservoir production on a real time, spatially distributed basis.

ACKNOWLEDGMENT

The authors acknowledge significant contributions of co-workers at CiDRA Corp. and OptoPlan A. S. to the work presented in this paper. Portions of this paper were presented at Offshore Technology Conference, OTC 8842, May 4–7 1998, Houston, Texas; and The 5th International Conference—Multiphase Technology Series, February 1999, Aberdeen, Scotland.

LITERATURE CITED

[1] Aspelund, A., et al., "Challenges in downhole multiphase flow measurements," SPE 35559, European Production Operations Conference and Exposition, Stavanger, Norway, 1996.
[2] Hartog, A. H., et al., "Distributed temperature sensing in solid core fibers," *Electron Letter*, Vol. 21, p. 1061 1985.
[3] Meltz, G., W. W. Morey and W. H. Glenn, "Formation of Bragg gratings in optical fibers by a transvers holographic method," *Optics Letter*, Vol. 14, p. 823, 1989.
[4] Brill, J. P., "Multiphase flow in wells," *Journal of Petroleum Technology*, January, 1987.
[5] Standing, M. B., "A pressure-volume-temperature correlation for mixtures of California oil and gases," Drilling and Production Practices, API, 1947.

THE AUTHORS

***Alan D. Kersey** is vice president and chief technology officer for CiDRA Corp. Before joining CiDRA in 1998, Dr. Kersey worked at the U.S. Naval Research Lab in Washington, DC, for 14 years in the area of fiber-optic sensing. He earned his PhD from the University of Leeds, United Kingdom. His work in applied fiber optics has led to over 100 journal and more than 150 conference publications. He was elected Fellow of the Optical Society of America in 1993.*

***Daniel L. Gysling** is technical director for flow measurement products at CiDRA Corp. Before joining CiDRA, Dr. Gysling spent five years working on fluid dynamics at United Technologies Research Center, a division of United Technologies Corp. He earned his Ph.D. in aeronautics and astronautics in 1993 from the Massachusetts Institute of Technology, Cambridge, Massachusetts.*

***Francis (Tad) X. Bostick III** is director of business development-seismic systems at CiDRA Corp. in Houston, Texas. Before joining CiDRA in 1997, he worked at Western Atlas International in Houston. His 15 years of experience are in the areas of surface-seismic and borehole-seismic data acquisition. He earned both his BS and MS degrees in electrical engineering from Stanford University in 1981 and is a member of SEG.*